CHAPTER 1

INTRODUCTION

1.1. SCOPE AND OBJECTIVES

Electric power systems are carefully designed to withstand mechanical forces associated with wind and ice loads. The mechanical design specification, fully developed in standards, gives good results in a wide range of climates. There is no equivalent quantitative, standards-based design process for electrical insulation in winter conditions.

There were occasional problems with insulators operating in winter conditions at high-voltage transmission levels up to 230 kV, along with hazards of pole fires on distribution systems that made use of wood insulation. The insulation problems were recognized more quickly as extra-high-voltage (EHV) lines moved out of remote areas with limited development and low pollution. With the widespread use of EHV equipment in urban and suburban winter environments, and the challenges of ultra-high-voltage (UHV) engineering, the special case of winter flashovers at air temperature close to the melting point has now become an important design constraint in several areas.

This book is mainly about the electrical performance of power system insulators when coated with various forms of ice or snow. The roles of insulator precontamination and pollution in natural precipitation are important, so

Insulators for Icing and Polluted Environments. By Masoud Farzaneh and William A. Chisholm

there is some overlap with the many studies of electrical performance of insulators in salt-fog and clean-fog conditions. The authors recognize that when conductors are weighted down by ice and snow, there are extreme loads on the insulators, towers, and poles, and that the low temperatures also affect the mechanical strength of the components. However, electrical problems with flashovers resulting from modest ice accretion on insulators are far more frequent than line collapse under heavy ice loads.

1.1.1. Problem Areas

The number of single-phase faults in transmission networks in winter increases substantially during and after accretion of cold precipitation, followed by a rise in air temperature above 0 °C. Farzaneh and Kiernicki [1995] reviewed problems from 11 countries. A detailed review of the North American experience, leading to significant event reports to the National Electric Reliability Council (NERC), was consolidated by Chisholm [1997]. Eighteen countries reported ice and snow electrical flashover problems in a 2005 CIGRE survey [Yoshida and Naito, 2005]. The flashover problems plagued 35 utilities with 400- to 735-kV transmission systems on both line and station insulators.

Worldwide, ice and snow test methods have been developed to a high degree of sophistication in Canada, Sweden, Japan, and China, with movement toward standardization in IEEE PAR 1783 [2008]. The topic has also been covered in panel sessions and papers at general conferences on insulation and high voltage such as:

- IEEE Power and Energy Society (*PES*).
- IEEE Dielectrics and Electrical Insulation Society (*DEIS*).
- Conseil Internationale des Grands Resaux Electriques (*CIGRE*).
- International Symposium on High Voltage Engineering (*ISH*).

Specialized conferences on icing such as the International Workshop on Atmospheric Icing of Structures (*IWAIS*) have also focused sessions on electrical flashover problems.

Geographically, the Köppen–Geiger World Climate Classification of cold regions, based on vegetation, can provide a good initial indication of where in the world there will be problems with electrical flashovers on insulators. The group-D (continental) climates are the ones having an average temperature above 10 °C in summer and below –3 °C in winter. There are few areas in the Southern Hemisphere, for example, highland New Zealand, that have this classification, so icing flashover problems are mainly the domain of the northern regions, shown in Figure 1-1.

There are two other aspects to the classification in Figure 1-1. The second letter in the D**x**y code has the following meanings:

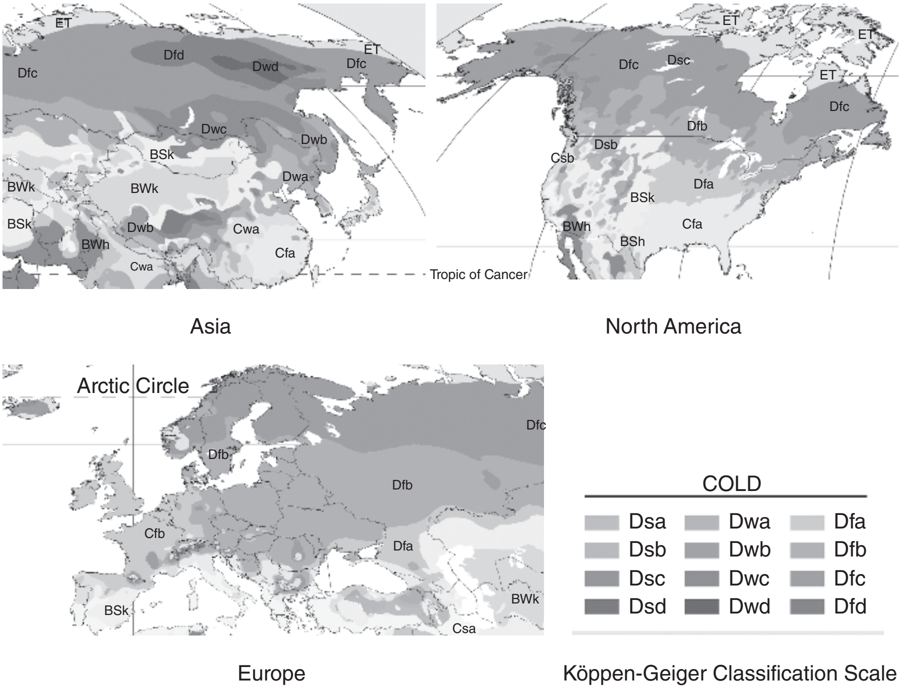

Figure 1-1: Köppen–Geiger classification of cold regions (from Norgord [2008]).

- Code s indicates an area with dry summer, with less than 30 mm precipitation and one-third of the amount in the wettest winter month.
- Code w indicates an area with dry winters, where the average winter month precipitation is less than 10% of an average summer month.
- Code f indicates significant precipitation in all seasons.

Generally, areas with relatively dry winters (code w) may be more prone to long-duration buildup of contamination, while those with heavy winter precipitation (codes f or s) will be more susceptible to problems from direct, short-term accretion of ice or snow.

The third letter in the Köppen–Geiger classification relates to the warmest monthly average temperature in summer temperature: a (above 22 °C), b (between 10 °C and 22 °C), and c (three or fewer months above 10 °C). This code is not relevant to icing performance except for areas with code d, indicating three or fewer months with mean temperatures above 10 °C in Siberia.

While it is formally classified as Cfb, the United Kingdom was the first country to report problems with flashovers in winter fogs at 0 °C on 132-kV and 275-kV systems. The code C reflects a coldest-month average temperature of somewhere between –3 °C and 18 °C.

1.1.2. Problem Characteristics

Many electrical flashover events in winter conditions have the following common features:

- A period of accumulation of pollution on insulator surfaces prior to the event, lasting from hours to months.
- Enough ice or snow accretion to fill in some of the space between insulator sheds or disks.
- Leakage currents that flow across insulators under normal operating voltage when ice, snow, or dew point conditions exist leading to ignition of pole fires if wood insulation is used in series with ceramic or nonceramic insulation.
- Flashovers that evolve slowly or quickly from leakage currents under normal operating voltage near 0 °C (32 °F), rather than in response to overvoltages from switching operations or winter lightning.
- Flashovers that occur from line to ground.
- Flashovers that occur seconds or minutes apart on parallel insulators that are exposed to the same conditions.
- Flashovers that occur mainly in areas near the sources of pollution.

These common factors lead to more problems at large transformer stations, with hundreds of insulators in parallel, rather than on lines where typical towers hold only three or six insulator strings in parallel.

The build up of pollution on insulator surfaces and the electrical characteristics of the ice, snow, or frost accumulation are dominant factors in winter flashover problems. In regions of major interest, the longest duration of exposure to pollution without cleansing rain occurs in the winter. Paraphrasing Brunnel [1972], "the winter is a desert with a perfect disguise." Also, in many of these countries, salt is used to ensure road safety under icing conditions. The road salt exposure is similar in most respects to ocean salt conditions. This brings forward an important task in this book: consolidation, use, and extension of existing methods used to evaluate insulator performance in contaminated regions.

Symptoms of icing problems also show up when drift overspray from cooling towers condenses onto cold insulators or when unfavorable wind direction blows sea salt spray or salt-laden wet snow directly onto insulators. The occurrence of dew point temperatures below freezing plays a role in these events, rather than freezing ambient temperatures.

1.1.3. Intended Audience

Reliability and power quality specialists for high-voltage networks, and their regulators, often question why outdoor insulators can fail some, but not all, of the time in winter conditions. Modest ice accretion at a moderate 0 °C winter temperature on one occasion can qualify as a major reliability event day, while many similar days pass each winter without power system problems. This book consolidates the authors' combined industrial and academic experiences with this problem, supplemented with a rich set of resources that include trouble reports from around the world originating in the 1930s, laboratory test results starting in the 1960s, and mathematical models for the flashover process that evolved in the 1990s.

Electrical utility design standards departments in many countries may refer to this book to evaluate why they have occasional unexplained reliability problems, often at dawn after a cool evening, and may not have recognized the critical role of melting temperature in their insulator flashover problems. Design engineers will also be able to assess the likely maximum pollution and icing severity at a substation or along an overhead line, and then select insulators that have appropriate withstand margins. Case studies and design tools in this book are useful guides for selecting and specifying the most appropriate insulators, bushings, and maintenance plans for the local winter conditions.

Electrical utility maintenance engineers and power system operators may need to explore root causes and quantify the cost of various mitigation options prior to making an informed recommendation for specific problem areas. The extensive coverage of mitigation options for four levels of icing severity is provided to help with this decision process. After studying the appropriate parts of this book, engineers and environmental specialists will also be able to carry out representative insulator contamination measurements, understand how these readings change with time and weather, and work out how the readings coordinate with the insulator dimensions in their existing networks.

The contents of this book lead toward a final chapter that demonstrates specific insulation coordination processes for the icing and polluted environment. Universities with programs in high-voltage engineering will find this to be a working example of how to introduce the uncertainties of real-life electrical engineering into quantitative evaluations of reliability. The process can be adapted to evaluating the risks of reliability issues with other types of adverse weather.

For engineering programs with some power system emphasis, the book may serve well as a graduate-level textbook for special topics in high-voltage electrical engineering, electrochemistry and environmental science for high-voltage engineers, insulation coordination, high-voltage transmission system design, or other courses in power engineering related to power transmission and distribution. Educators will also understand why the ice surface flashover is well behaved compared to conventional pollution flashover, making it much more suitable for demonstrations, modeling, and analysis by researchers and graduate students working in this area. The study of electrical flashover on iced or polluted and frosted insulators is also an interesting and accessible introduction to more difficult problems of insulation coordination in conventional pollution conditions for the electrical utility engineer or student in engineering or risk management.

1.2. POWER SYSTEM RELIABILITY

The modern electric power system is a complex organization of large machines, highly integrated with transmission and distribution systems for delivering continuous and real-time service to customers. At present, the ability to store electrical energy is limited mainly to the rotating inertia of the generators. This means that a fault in any of the equipment functional zones—generation, transmission, and distribution—will lead to customer disturbances. These disturbances may be minor—a voltage dip of less than 10% for a fault far away—or can be significant, if it leads to misoperation or damage of customer equipment.

The degree of customer satisfaction with the output of the electrical system is a strong function of the perceived reliability, which is the ability to supply the demand at any moment, under any circumstance, including adverse weather. Utilities and their regulators have always been concerned with measuring reliability by examining line and station fault rates, generator availability statistics, and other related data.

The occupation of the power system planner, especially for EHV systems, is to develop a design that offers the best trade-off between cost and reliability. While investment costs in lines and generating stations are relatively easy to calculate, the trend has been to include societal costs, such as visual impact, that are much more uncertain in this evaluation. The evaluation of reliability has always accommodated uncertainty, as there are constant interactions among power system components, and also large numbers of states that can satisfy the demand in a satisfactory way through the general use of fault tolerance.

1.2.1. Measures of Power System Reliability

In the United Kingdom, problems with winter-related insulation failures date from about 1935. Coincidentally, the UK Electricity Supply Regulations of 1937 specified four objectives that have evolved as follows [Argent and Hadfield, 1986]:

- To develop and maintain an efficient, coordinated, and economical system of bulk electricity supply.
- To provide a constant supply *except in case of emergency.*
- To maintain the supply frequency within ±1% of 50 Hz.
- To maintain the customer's supply voltage within limits of ±6% of the declared value.

The first, economic objective is balanced against the other three measures of reliability and security of supply. A "case of emergency" at the Central Electricity Generating Board (CEGB) was judged to be an event interrupting more than 1500 MW of customer load. In the traditional deterministic approach to power system planning, three transmission circuits would thus be needed to connect two large generators to the system. This configuration would provide full output following the loss of any two of the transmission circuits. Clearly, a common set of faults at the electrical substation supplying these three lines would have more severe consequences. This has led to development of probabilistic methods that consider the variation in probabilities and consequences of faults [Argent and Hadfield, 1986] at CEGB and many other large, regulated utilities.

In North America, standards for reporting the reliability of generation facilities are also well established, using component availability statistics. Of particular interest are historic forced outage rates, which are used to extrapolate the probability that the unit will be unavailable at some time in the future, and also the mean time to repair a unit after a typical or unexpected fault. Generators may also have partial failure modes, as they may be derated for some periods of time to respect temperature or emission limits.

Transmission and distribution systems tend to have "clean" failure modes and fast times to repair in most cases. The restoration time could be the days needed to replace a transformer with a spare component, or the milliseconds needed to perform switching actions to isolate and clear a fault. Generally, transmission system forced outages are classified in units of *outage per 100 km per year*. Momentary outages include those that are detected by relays, cleared by protective equipment, and successfully reclosed in the case of transmission systems. Sustained outages are classed as those with duration of more than 1 minute [Billington, 2006] by the CEA Equipment Reliability Information System [CEA, 2002, 2004]. Also, outages are segregated by voltage class, as many adverse weather hazards such as lightning tend to diminish as insulation levels increase.

There is a strong trend in Figure 1-2 toward reduced rates of sustained outages with increasing voltage level, while terminal problems are more severe for EHV systems. This reflects the fact that electric field stresses across

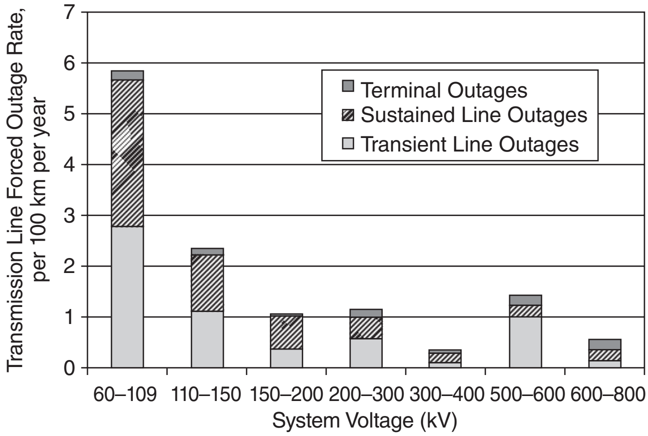

Figure 1-2: Sustained and transient forced outage rate performance of transmission lines (data from Billington [2006] and CEA [2002]).

insulators are 30–50% higher on EHV equipment than stress on typical HV systems.

There are two main measures of power system reliability that form the basis for industry comparisons. With their wide acceptance, these indices are being used as well by electric utility industry regulators.

- SAIFI is the System Average Interruption Frequency Index, given by the number of delivery point interruptions, divided by the number of delivery points monitored. It is usually averaged over a year. Areas of high lightning incidence may have a high level of SAIFI, caused by frequent but brief interruptions. To get around this, most utilities disregard outage durations of less than 1 or 3 minutes in their data collection. As a general guide, IEEE Standard 1366 [2003] reported a median value for North American utilities of 1.1 interruptions per customer with this adjustment.
- SAIDI is the System Average Interruption Duration Index, given by the total duration of all interruptions, divided by the number of delivery points. It is also reported as an annual value and sometimes converted to "system minutes." A median value of 90 minutes per year in IEEE Standard 1366 [2003] has been steadily improving at most North American utilities in response to regulatory incentives.

With the sensitivity of industrial process equipment to momentary outages, caused by the operation of protective equipment, there is increasing interest in the measure of MAIFI, or Momentary Average Interruption Frequency Index. In a Japanese survey [CRIEPI, 2004], 41% of customers' concerns were related to instantaneous voltage dips of less than 0.1 s, and another 13% were concerned with voltage fluctuations, compared to only 15% who worried about power outages of long duration. The MAIFI is given by the number of momentary outages, typically with a voltage dropout of 50% or more, divided by the number of delivery points.

The MAIFI has proved to be highly sensitive to the local level of lightning activity. Since, in many regions, there are significant variations in the ground flash density from year to year, it has become common to monitor the number of cloud-to-ground flashes in a region and to normalize the MAIFI values against this annual value. This is a desirable practice in weather normalization that is feasible because there are wide-area systems for monitoring lightning density. An example of the strong correlation for a specific area of a distribution network is given in Gunther and Mehta [1995]:

$$[\text{Sags/Month}] = 2.09\, N_g + 0.9, \quad r = 0.991 \tag{1-1}$$

where

[Sags/Month] is the number of voltage dips, typically less than 10 ac cycles in duration and larger than 10% of nominal voltage,

N_g is the lightning ground flash density (flashes/km^2/yr), and
r is the Pearson correlation coefficient.

For other adverse weather risks that lead to significant outages, the task of weather normalization is of great interest but is hampered to some extent by the limited measures of occurrence. One innovation in IEEE Standard 1366 [2003] for distribution system reliability measurement is the definition of a *major event day*. This recognizes that there are typically two modes of power system operation:

- A day-to-day mode, with reliability problems that a utility has come to expect and with planned response, putting the right staff and materiel in place as part of normal operation.
- A major event day that typically calls for emergency response procedures, including staff overtime, maintenance, or replacement procedures that, for example, have a place in the annual budget but no clear expectation of where or when the resources will be required.

The segmentation of reliability data into these two distinct sets allows utilities to analyze and report the activities that occur on major event days, and to assess their day-to-day performance against regulation targets or previous achievements on a more consistent basis.

The quantitative measure of whether an adverse weather event is a "major event day" uses a simple metric—when the SAIDI for the day is more than 2.5 standard deviations away from the daily mean SAIDI. This is known as the "2.5-Beta" method in IEEE Standard 1366 [2003]. This provides a good indication of the days on which an electrical network is experiencing stresses, such as severe weather, that are beyond those normally used.

There can be some odd results when the 2.5-Beta method is used in areas where specific reliability risks are low or high. Taking, for example, portions of the west coast of the United States, the lightning ground flash density and number of days with thunderstorms are low. Any day with lightning is classed as a "major event day." In contrast, in the southeast United States, the lightning flash density is up to 20 times greater, and dealing with the lightning activity that peaks every summer afternoon at 4 PM is a part of normal utility operation, not a major event day, using the same 2.5-Beta criterion.

Mechanical failures of transmission and distribution systems under severe ice, snow, or wind conditions typically qualify as major event days. One of the goals of this book is to indicate that there may be days with moderate ice accretion and other weather conditions, notably melting temperatures, which also qualify as major events when they lead to repeated flashovers of station and line insulators on the most critical HV and EHV networks.

1.2.2. Achieving Reliability with Redundant Components

The transmission line forced outage rates reported by Billington [2006] in Figure 1-2 are based on Canadian data and introduce an interesting anomaly for 500-kV systems. One reporting utility accepts a very high rate of 500-kV transient line outages [Mousa and Srivastava, 1989] as a consequence of the economies it achieved by eliminating overhead groundwires. Every lightning flash to the unprotected phases causes a flashover and circuit breaker operation, whether from the initial surge or from one of the subsequent strokes that follows the same flash. This is an example where a low level of component reliability, in this case transmission lines with lightning tripout rates of six to nine outages per 100 km per year, can still provide high system reliability, because resources not allocated to overhead groundwires were diverted to construction of redundant 500-kV lines along main point-to-point power transfer corridors.

In many places, the EHV networks are configured as grids. This provides a number of redundant paths for power delivery and can be particularly effective in icing conditions. A plan for operating the power system with the complete loss of a single substation may be effective for these areas. This would move the risk of repeated icing flashovers from a Class D to a Class C category in the NERC Definitions of Normal and Emergency Electric Power System Condition (given later in Table 1-2).

Long-range transport of energy using ac or dc EHV or UHV transmission lines may not have the luxury of redundant stations or parallel paths. The design of the series components of these systems to withstand the anticipated icing and contamination environments is thus more critical to the delivery of reliable and continuous electrical service.

1.2.3. Achieving Reliability with Maintenance

Icing problems causing electrical flashovers of insulators are a good example of a hazard to power systems that can be addressed with reliability-centered maintenance. A reliability-centered maintenance program is a series of orderly steps [IEEE Standard 100, 2000] for:

- Identifying system and subsystem functions, functional failures, and dominant failure modes,
- Putting the failure modes in priority order, and
- Selecting applicable and effective preventive maintenance tasks to address the classified failure modes.

The dominant failure modes—insulator line-to-ground flashovers under melting conditions—are identifiable in the case of icing problems. The risk of icing failures can also be established based on experience and modeling, to place the hazards into their correct priority compared to other power system risks. Finally, there are a fairly wide range of preventive maintenance options that can be used to prevent future failures.

1.2.4. Cost of Sustained Outages

Utilities are often careful to tally the number of customers affected, and to total up the costs of restoring service, after severe outage events. As an example, ampacity problems with low wind conditions on August 14, 2003 led to a widespread blackout that affected 50 million customers and led to financial losses estimated at US$6 billion. This represents a loss of $120 per person per day. The severe 1-week ice storm in eastern Canada and the United States in January 1998 also cost the economy about US$6 billion. For the 700,000 people without power for up to 3 weeks, the specific power system restoration costs were about US$2 billion, working out to $140 per affected person per day.

1.2.5. Cost of Momentary Outages

There are two ways to estimate the cost of a momentary voltage dip or dropout. One way is to evaluate what a utility typically and specifically spends to eliminate common sources of line-to-ground faults. The other way is to survey customer perception and behavior, for example, in the costs associated with battery backup or redundant supply to critical loads, with lost production or other factors.

Chisholm and Anderson noted in EPRI [2005] that the cost of lightning protection on overhead transmission lines can be broken out of the overall line cost and then used to establish utility spending to avoid customer momentary dips. The additional cost of overhead groundwire protection includes three components:

- The capital cost of the wires and the heavier, taller towers to support them.
- The energy cost of induced currents in the overhead wires at average load.
- The cost of providing additional capacity to meet the induced currents at peak load.

These costs varied considerably with system voltage and line configuration, with single-circuit horizontal EHV lines having the greatest losses at peak loads. Double-circuit lines with low-reactance phasing (ABC/CBA) had peak losses that were eight times lower than lines with superbundle (ABC/ABC) phasing.

The benefits of lightning protection can be calculated from the outage rate of the line, with and without overhead groundwires. After expressing the power transfer in terms of affected customers for each phase-to-ground fault, it was possible to establish a median cost per avoided customer momentary outage of about US$0.08 for single-circuit lines and $0.02 for double-circuit lines with low-reactance phasing.

The benefit of lightning protection scales linearly with the lightning ground flash density. For areas with a ground flash density of 10 rather than 1 flash/km^2, the utility spending to avoid each customer momentary dip will be a factor of 10 lower.

It is far more effective for electrical utilities to mitigate momentary lightning outages than for the customers to undertake this protection. As an example, a customer worried about momentary disturbances from lightning flashes to a 230-kV line affecting a computer may purchase a battery-operated laptop or an uninterruptible power supply system. The customer options tend to have costs of $0.30 to $70 per avoided momentary dip [Chisholm, 2007] compared to utility options such as improving the grounding of towers ($0.03 per avoided dip), fitting some transmission line surge arresters (about $0.08 per avoided dip), or replacing 2-m insulator strings with 3-m strings ($0.15 per avoided dip).

There is also a wide gulf between what utilities spend to avoid customer momentary dips, and what the customers perceived and reported as their costs for each dip. Industrial customers advise that the cost of a momentary disturbance is on the order of $4 to $16 per kW of load [IEEE Standard 493, 2007]. An EPRI survey [CEIDS, 2001] went further, surveying all sectors of the industrial and digital economy, and estimated the annual cost of power system outages for all business sectors. These data are sorted in Table 1-1 according to the relative incidence of winter icing and fog conditions, measured by the number of days with snow cover.

While there are some regions, such as California, that do not face the direct effects of winter conditions, much of the energy supply to this region must traverse areas to the north where there are at least 84 days of snow cover per year. Even ignoring this fact, and using the median area values for snow cover in Table 1-1, the weighted sum of all electrical outage problems that occur in

TABLE 1-1: Cost of Electric Power System Outages by Region, Along with Average Number of Days with Snow Depth Greater than 25 mm

Region	Median Number of Days with Snow Depth >25 mm	Estimated Annual Cost of Outages, $US\$_{2001}$ (Min–Max)
New England	84	6.1–9.6
Middle Atlantic	56	15.4–24.3
Mountain	56	6.1–9.5
West North Central	42	8.1–12.6
East North Central	35	17.3–27.0
South Atlantic	7	18.3–20.7
East South Central	7	6.3–9.9
West South Central	3	11.2–17.6
Pacific	0	16.2–25.2

Source: CEIDS [2001] and NOAA.

winter conditions falls between US$8 and US$12 billion per year for the United States.

An interesting point was raised in the CEIDS [2001] study, related to the effect of multiple reclosing sequences on customer loads. It is normal for utilities to protect against transmission system insulation flashovers of all sorts with automatic circuit breakers. Customers reported that the average cost of equipment damage after such a recloser operation was more than $2000, while the median value for any other outage duration was only $550. This was attributed to the strain of stopping and restarting machines and processes so quickly. The occurrence of several icing flashovers in a short period of time, each leading to a recloser operation, will exacerbate this problem for some customers.

1.2.6. Who is Responsible for Reliable Electrical Systems?

Electric power system reliability has many stakeholders, including:

1. Reliability coordinators.
2. Regional reliability organizations.
3. Transmission operators.
4. Balancing authorities.
5. Generator operators.
6. Transmission service providers.
7. Load-serving entities.
8. Purchasing–selling entities.

In the United States, the National Electric Reliability Council (NERC) gives reliability coordinators in their specific areas the mandate to redispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the electric power system to a reliable state. Reliability coordinators can delegate tasks to other stakeholders, but this delegation does not change their responsibility to comply with NERC and regional standards and to act fairly.

The design of a reliable transmission system places higher costs on transmission service providers. An alternative, which is to operate around problems by allowing selected failures, shifts these costs to the transmission operators and may also affect the ability of generator operators to deliver power into the grid.

Operation of the transmission system also has important rules and regulations that may be relevant, including identification of severe weather and emergency operating procedures in effect. NERC Standard TPL-003 classifies the normal and abnormal system operation as shown in Table 1-2.

NERC Standard TPL-003-00 [2005] also mandates that power systems should be designed to limit cascading outages for Category A, B, and C

TABLE 1-2: NERC Definitions of Normal and Emergency Electric Power System Condition

Category	Initiating Events and Contingencies	System Limits or Impacts
A: No contingencies		No loss of demand or curtailed firm transfers
B: Event resulting from the loss of a single element	Loss of an element without a fault. Single line-to-ground (SLG) or three-phase (3ϕ) fault and normal clearing: 1. Generator 2. Transmission circuit 3. Transformer Single-pole block and normal clearing: 4. Single pole (dc) line	System stable; thermal and voltage limits within ratings
C: Event(s) resulting in the loss of two or more (multiple) events	SLG fault with normal clearing: 1. Bus section 2. Breaker (failure or internal fault) 3. Type B fault, manual System adjustments, followed by another Type B fault: 3. Bipolar (dc) line fault with normal clearing 4. Fault on any two circuits of multiple circuit tower line with normal clearing SLG fault with delayed clearing (stuck breaker or protection system failure) on: 5. Generator 6. Transformer 7. Transmission circuit 8. Bus section	Loss of demand or curtailed firm transfers

D: Extreme event resulting from two or more (multiple) elements removed or cascading out of service	3ϕ Fault with delayed clearing on: 1. Generator 2. Transformer 3. Transmission circuit 4. Bus section 5. 3ϕ Fault with normal clearing of breaker failure 6. Loss of tower line with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another regional reliability organization.

Source: NERC Standard TPL-003-00 [2005].

conditions. However, widespread ice storms or contamination problems with multiple line-to-ground faults in stations and lines can often lead to loss of a substation or switching station, leading to a Category D condition. For these events, system performance is evaluated for risks and consequences of:

- Substantial loss of customer demand and generation in a wide area, and
- Inability of parts or all of the interconnected systems to achieve new, stable operating points.

Evaluation of these Category D events may require joint studies with neighboring systems.

1.2.7. Regulation of Power System Reliability

Voluntary standards for electric power quality have been negotiated among industry groups such as Information Technology Industry Council [ITIC, 2005] and electric utilities. This is expressed as an envelope of tolerance around the nominal ac voltage at the customer premises. Household (120/240 V) supply voltage that stays inside this envelope can be tolerated with no interruption in function by most information technology equipment. While the compliant equipment would not be damaged by a short-duration voltage reduction, a drop of line voltage to 70% of nominal for more than 20 ms would lead to an interruption in function—for example, a reset of a computer or machine control system. This means that, even if automatic protective relaying and successful reclose operations occur after a power system fault, many pieces of customer equipment will still be affected, since even the best high-speed breakers take more than 20 ms to complete their open-and-reclose function.

Some industries, such as semiconductor processing, have opted to improve the tolerance of specialized process equipment to short-duration dropouts. However, many more are relying increasingly on regulatory pressure. This has evolved into modern electric power system reliability standards, for example, the US Energy Policy Act of 2005, that set out responsibilities and reporting requirements. In order to ensure compliance, regulatory agencies have discretion to apply sanctions whenever a violation is verified. The prior attitude within an organization toward regulatory reporting and its commitment to meeting responsibilities is an important factor in the level of sanction that is levied. By recognizing insulator faults under icing and polluted conditions, utilities can be more confidently prepared for regulatory audits of their reliability compliance program.

1.3. THE INSULATION COORDINATION PROCESS: WHAT IS INVOLVED?

There are two main aspects in the process of insulation coordination. These are the design of insulation systems to withstand overvoltages, and the design to withstand adverse weather.

The most common example of an overvoltage related to adverse weather is the lightning surge. In general, the lightning performance of a transmission line is calculated with statistical methods that have a high state of development. Provided that the main input data, such as the distribution of soil resistivity or footing resistance and the local ground flash density, are known with sufficient detail and accuracy, the quality of prediction of lightning outage rates is very good. As an example, there is a strong linear relation between annual ground flash density and the number of lightning outages on the Japanese high-voltage transmission networks [Ishii et al. 2002].

There have been fewer reports of the performance of transmission line failures under constant line voltage and adverse contamination and wetting conditions. One recent summary was provided by Gutman et al. [2006] and important details are summarized in Table 1-3.

To date, there has been no organized presentation of the typical outage rates of power systems under ice and snow conditions that cause insulator flashovers because the incidence rates are low, even compared to the number of pollution events in Table 1-3 for Norway. Instead, experience has been consolidated in papers such as those of CIGRE [TF 33.04.09, 1999; TF 33.04.09, 2000; Yoshida and Naito, 2005], IEEE [Farzaneh et al. 2003, 2005, 2007; IEEE PAR 1783, 2008], and CEATI [Farzaneh and Chisholm, 2006].

1.4. ORGANIZATION OF THE BOOK

The remainder of the book is organized as follows.

Chapter 2 describes the general nature of electrical insulation, with a focus on HV and EHV systems. The chapter identifies terms used to describe the various electrical stresses that occur in service and introduces the standard tests used to quantify electrical strength.

Chapter 3 introduces the methods and terminology used to describe the effects of the natural environment on the insulation systems. The role of environmental pollution in the electrical conductivity of wetted surface deposits and of the precipitation itself is built up from the background measurements. Then, for the important and specific pollution sources such as the ocean, road salting, or cooling tower effluent, suitable pollution accumulation models are consolidated from literature around the world. Enough practical electrochemistry is provided for users to carry out their own evaluations of the electrical conductivity of local pollution and precipitation.

Chapter 4 describes the various test methods that have evolved to reproduce the natural processes of contamination build up and wetting. Representative test results from salt-fog, clean-fog, and cold-fog tests are shown. Empirical models are developed to interpolate some important results to give initial insight about how the physical processes of contamination flashover vary with contamination level, voltage stress, leakage distance, and other insulator characteristics. This chapter also suggests that the cold-fog flashover

TABLE 1-3: Comparison of Pollution Flashover Rates of Transmission Lines in Norway, Russia, and South Africa

Country	Line Voltage (kV)	Line Length (km)	Altitude (km)	Number of Pollution Events per Year	ESDD and NSDD (mg/cm^2)	Contamination Flashover Rate per 100 km-yr
Russia	117	148	200	200	0.13[a]/1.0	0.43
	119	87	200	150	0.04[a]/0.5	1.43
South Africa	400	163	100	72	0.1/0.5	0.6
	400	60	1600	40	0.1/0.5	1.0
	400	74	1500	40	0.1/0.5	0.17
	400	336	1200	15	0.06/0.5	0
Norway	420	106	200	10	0.1/0.1	0
	420	134	1200	10	0.05/0.1	0
	420	118	650	8	0.1/0.1	0
	300	48	200	5	0.1/0.1	0

[a]Using conversion of layer conductivity (μS) = 71.2 $(ESDD)^{0.786}$

Source: Adapted from Gutman et al. [2006].

of polluted insulator surfaces is a relatively simple extension of the clean-fog flashover mechanism.

Chapter 5 on modeling of the contamination flashover builds on the knowledge gained from Chapters 3 and 4, using the likely resistance of a polluted and wetted insulator surface, and the observed effects that this has on electrical strength. These data are inputs to mathematical modeling that was developed starting in the 1980s to predict the ac voltage stresses that will lead initially to arcing and, at higher stresses, to flashover.

Chapter 6 reviews the wide variety of methods and options for improving the leakage distance flashover performance of insulators in polluted environments. Examples are drawn from both laboratory and field exposure. Results are compared with the empirical and theoretical models of flashover strength.

Chapter 7 on icing flashovers takes advantage of the ability to study flashover in controlled conditions to build a series of mathematical models for very light, light, moderate, and heavy icing severity. These four levels of severity are also used to organize the available test results in a wide range of conditions.

Chapter 8 completes the treatment of winter precipitation by analyzing the effects of dry and wet snow on the insulators. As in Chapter 6, a combination of visual observations, leakage current measurements, and results from several different physical scales are presented in an organized sequence.

Chapter 9 reviews the wide variety of options for improving flashover performance of insulators in icing environments. Case studies describe utility experiences with a number of different methods to deal with recurring winter flashover problems. These include ways to keep ice from forming (heat lamps or booster sheds), ways to deal with build up of ice pollution (SMART washing or steam cleaning) and ways to make insulators perform better (modified insulator surfaces or accessories).

Chapter 10 closes two loops by the insulation coordination process selection of dry arc and leakage distances. The existing process for selecting an appropriate leakage distance for contaminated environments is adapted for freezing conditions. Statistical modeling is introduced to set this contamination flashover problem into the overall context of substation and transmission line reliability evaluation. This can be done because the numerical models developed for pollution flashover actually work even better in cold-fog conditions, once arc parameters are corrected. Provision of adequate leakage distance is usually not onerous: the electrical industry has been successfully adapting leakage distance to local environments for more than 160 years. Cold-fog conditions in winter are an additional factor—the "winter desert with a perfect disguise"—that must be considered as a severe problem for EHV systems constructed near expressways subject to road salting.

Chapter 10 also treats the selection of an appropriate insulator dry arc distance. Unlike the selection of leakage distance, where there is a strong set of precedents and standards, the advice in this chapter is relatively new and, while well supported by test data, remains to some extent based on analytical and empirical models of the flashover process. Since the provision of adequate dry arc distance for all conditions can be very costly and affects insulation coordination of costly components such as transformers and circuit breakers, it is very important to place the icing problem within the overall context of substation and transmission line reliability evaluation.

1.5. PRÉCIS

Power systems achieve excellent overall levels of reliability, as measured by the frequency and duration of interruptions. This reliability is achieved through a combination of redundancy—such as a grid of parallel paths—and adequate performance of individual components such as transmission lines and stations.

Adverse weather of all types has a strong effect on reliability of power system components. Risks from lightning in summer storms are well understood, and protection measures are adapted to the local climate. The costs of this protection are balanced against regulatory requirements using SAIDI, SAIFI, and MAIFI metrics. The same process is not well established for risks from icing and contamination flashovers in winter. This book addresses the rational selection of station and line insulators in areas where these problems recur occasionally or frequently.

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References and bibliography for further study are provided at the end of each chapter. Also, the figures for this book and electronic links to relevant papers in the IEEE Xplore system and the public domain will be available at the following IEEE/Wiley web site, using the access code provided with this volume: www.ieee.org.

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